23 January 2017

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Pierce

Distribution Market Model: Approach Paper

Energy Queensland Limited (Energy Queensland) supports the Australian Energy Market Commission's (AEMC) Distribution Market Model project. Over the long term the mass adoption of Distributed Energy Resources (DER) will have significant impacts on distribution networks and the requirement to manage these issues is clear.

In doing so, a careful balance needs to be stuck between the need, which we strongly support, for DER to develop unencumbered in the market; and the need to ensure consumers are provided a safe, secure and reliable energy supply. As the energy provider of last resort these regulatory obligations are incumbent on Distribution Network Service Providers (DNSPs). It is thus difficult to envisage a market framework wherein a third party could be responsible for the operational functioning of aggregated DER; the import / export management of which will impact DNSPs' capabilities to meet their regulatory obligations.

Further, Energy Networks Australia and the CSIRO's Energy Transformation Roadmap outlines a comprehensive transition pathway towards 'Smart Grids' and Energy Queensland strongly supports the AEMC engaging in this work as part of its Distribution Market Model project, as the two are closely aligned. As this research shows, any emergence of a Distribution System Operator will be a transition that may occur and must be managed over time.

Should you require additional information or wish to discuss any aspect of this submission, please do not hesitate to contact either myself on (07) 3851 6416 or Trudy Fraser on (07) 3851 6787.

Yours Sincerely

Jenny Doyle
General Manager Regulation and Pricing

Encl: Energy Queensland's Submission and response to the consultation questions.

Energy Queensland

Distribution Market Model

Submission to the Australian Energy Market Commission:
Approach Paper

Energy Queensland Limited
23 January 2017

Contact details

Energy Queensland Limited
Jenny Doyle
Phone: +61 (7) 3851 6416
Email: jenny.doyle@energyq.com.au

PO Box 1090, Townsville QLD 4810
Level 6, 420 Flinders Street, Townsville QLD 4810
www.energyq.com.au

Energy Queensland Limited ABN 96 612 535 583

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1 Distribution Market Model: Overview

1.1 Energy Provider of Last Resort

Energy Queensland considers there are two fundamental considerations when examining future 'Distribution Market Models', and the potential role of a Distribution System Operator (DSO) to manage the cumulative impact of distributed energy resources (DER).

Firstly, Distribution Network Service Providers (DNSPs) are the energy provider of last resort. In the absence of predominantly solar energy, or when systems fail, customers will require their energy to be delivered by DNSPs, including the supply required for their DER. As no other market participant can perform this 'last resort' function for the entire customer base with the level of expected safety and reliability; the regulatory obligation to ensure a reliable energy supply will remain upon DNSPs.

Secondly, energy usage naturally occurs in a tiered manner, with consumption and generation being firstly on site, moving beyond that to local area and ultimately to inter-city consumption.

1.1.1 Technical Limitations of this Market Framework

Energy Queensland considers the fact that DER in aggregation will impact the functioning of distribution networks is clear. Essentially therefore, any requirement for a DSO function will likely evolve from an extremely localised management system, to state wide management over many years. The operational decisions of any DSO in its management of distributed energy will then impact at increasing levels the capability of DNSPs to meet their obligations to provide a reliable, safe, and secure electricity supply. Without significant and even radical change to these DNSP obligations, if in fact this is possible given the natural requirement for DNSPs to act as supplier of last resort, Energy Queensland does not consider that a DSO function can reasonably fall to a party other than the DNSP itself.

Also critical to note here, is that the handover time lag between any potential third party DSO and the DNSP also means that it is not likely to be technically feasible for anyone other than the DNSP to perform a DSO role. Further, the need for a DSO, while apparent, could still be mitigated via technology and smart grids. The creation of another role in the market could result in a model that would only add costs to customers for a service that appears the role of distribution networks, supported by any necessary and appropriate protocols. We note that the Energy Networks Australia's submission explores in more detail the staged evolution towards smart grids / the DSO role and the appropriate pathway in this regard. It is also important to consider it is unlikely that one national body could reasonably have direct control of distribution systems with DER in a centralised capacity. Specifically, each jurisdiction and DNSP has a range of differing rules, customer types, technologies, network configurations and network technologies.

Essentially, the DSO function could be performed within a single DSNP or over a single state (where possible). However, it would be unable to be performed at a national level due the complexity in differences between the states and the sheer volume of DER. Having a DSO function per state would provide the capability to compile the necessary data to provide to AEMO at a cumulative local level, as it requires.

2 Regulatory Environment

Energy Queensland considers protocols should be developed to ensure the system operator functions fairly, reasonably and cooperatively across the market. The market should be enabled to develop unencumbered and application protocols should be developed to cover 'last resort' DER access to ensure distribution networks are not compromised by the integration of 'generation', as already occurs with the transmission system. In Queensland, the basis of such a framework is already in place.

2.1 Jurisdictional Obligations

As noted by the AEMC, jurisdictional legislation place obligations on DNSPs to provide and maintain safe electricity supply to consumers. In Queensland Section 36 of the *Queensland Electricity Regulation 2006* (*Regulatio*n), includes a requirement on DNSPs to consider the interaction of customers' "electrical articles" on the network and to take action if the installation is likely to "unreasonable interfere" with supply to other customers. Essentially, therefore section 36 of the *Regulation* already places the DSO role on Energex and Ergon Energy and Queensland DNSPs. While this section was clearly not drafted for the purpose DER, its presence demonstrates an understanding that the DNSP is the only party that can monitor and mitigate the impact of third party electrical installations on their networks. The impacts of DER are not isolated to any one element of the power system. Specifically a coupling exists via the electrical connections of the grid which causes the various elements to interact in ways that can be detrimental to networks if not addressed; and that can only be adequately managed by the grid operator. Further detail on the technical reasons for this is outlined in our response to the questions raised in the Consultation Paper.

What is required for any DSO role is an operating framework with clear obligations on market participants to act cooperatively, and a clear description of the circumstances in which a DSO is permitted to act. This will enable a transparent and open market with clear accountability and reporting requirements.

2.1.1 Costs

The integration of DER into distribution networks will require a clear and careful allocation of costs.

DNSPs are generally responsible for ensuring acceptable voltage and power quality; however the voltage at a site with DER may be impacted significantly by the operation of the DER itself. Further, if the DER is used for market purposes its operation on mass may cause voltages to be outside of regulatory limits and fault levels above equipment ratings, issues and costs for which the DNSP will be responsible. Energy Queensland considers that in such cases the costs of maintaining acceptable voltage and power quality on the network should be shared by the participant who is receiving a market benefit from the DER. Otherwise, DNSPs will be required to fund stability measures offered by the manufacturers of DER to mitigate any issues. This would see the DER market profit from the supply of stability measures to manage the impacts it creates and would also result in a potential cross subsidy in the market.

Preventing such cross subsidies from emerging will require a new regulatory framework for DER operation, the careful allocation of costs, and measures to ensure new technology is able to be utilised at the lowest cost.

3 Australian Standards & Tariffs

3.1 Tariff reform

As noted by the AEMC, tariff reform and the capability to send signals to customers or their agents to utilise distribution networks in the most efficient manner, is crucial to the cost-effective integration of DER and should be an important element in the design of future market models. The AEMC highlights that the “efficient adoption of DER may require the provision of price signals or the imposition of standards” and that in the longer term DNSPs may need to move from “being asset owners and operators to being providers of market platforms that send signals to incentivise the efficient integration” of DER. However, while tariff reform is fundamental to improving the utilisation of assets, tariff reform by itself is not a solution. System security will require a dynamic, fast, and complex response, which tariff signals are not of themselves, capable of providing.

Compounding this issue is that current customer participation in dynamic tariff programs is limited. With the complexities of customer side technology, customer move in/move out, rental properties (etc.) there is significant risk that customers will choose not to participate in different tariff options. Further still, pricing signals alone can negatively impact the network, for example, Electric Vehicles/batteries are likely to begin charging when the price to recharge drops. These variables make it essential the required technology is in place and capable of responding when market mechanisms are unable to provide the required control to maintain network stability.

3.1.1 Australian Standards

As such remote control capability of DER should be reflected in Australian Standards for this equipment. This need is also demonstrated by the presence of this project in itself, as a DSO will require remote access to manage DER and to ensure it does not negatively impact distribution networks. It can further be noted here that in regards to pricing signals, research also demonstrates that these alone are not sufficient to secure meaningful maintenance of loads, with third-party control capabilities therefore needed before reliable demand response of DER is achieved.[1]

4 Transmission Vs Distribution Systems

Energy Queensland notes the AEMC is of the view that distribution networks are not fundamentally different to transmission networks, in that both share the same laws of physics and comprise the same fundamental components; essentially making a distribution system with distributed energy resources a transmission system on a smaller scale.

However, Energy Queensland considers from a technical standpoint there are many other additional factors which distinguish the two. These include:

- Transmission networks have significantly more remote control, and are typically more meshed, which is important in the management of DER.
- Current and voltage management is more difficult at the distribution level and imbalance is usually not seen at the transmission level.
- Distribution networks will have different stability impacts to transmission networks. Specifically distribution networks will typically accommodate a very large number of DERs, resulting in increased power quality impacts (voltage fluctuations and harmonics) and islanding impacts.
- The level of technical and engineering capability and functionality such as protection, communication, control and operational capability that can be required for distribution customer connections is less than that which can be required in respect of transmission connections. These constraints can have impacts on uptake rates, response capabilities, localised climate impacts, etc. and should therefore be considered as part of any investigations.
- Data held in respect of distribution networks is typically not of the standard held in respect of transmission networks. This is particularly the case for deeper areas of the network, and given the relative size of such networks, the cost of improving access to data is currently prohibitive.

[1] Faruqui & Sergici (2013). *International Evidence on Dynamic Pricing*, pg. 5 concluding statement to the first paragraph states: “The use of enabling technology appears to increase demand response to levels above pricing-only observations for a given price ratio.”

- Transmission systems gain a greater benefit from diversified loads, where-as distribution systems can be impacted more heavily by the lack of diversification. For example, sudden cloud cover in one specific spot can remove all the solar PV generation off a distribution network, resulting in a step change in network loading.

These are only some of the key differences between transmission and distribution systems; others are discussed in detail in our attached response to the questions raised in the Approach Paper. In Energy Queensland's view, these differences demonstrate the inappropriateness of applying transmission based solutions to distribution networks.

Distribution Market Model – Energy Queensland Limited Feedback

Consultation Paper Feedback Question	Energy Queensland Comment
Objective of this project	
Do stakeholders agree with these definitions, or have any views on the project scope as a result of these definitions?	‘Distributed energy resource’ (DER) is a term that has been used for quite some time in the distribution industry to define generation (e.g. solar photovoltaics (PV)) or storage devices that are distributed throughout the distribution network. As such, Energy Queensland Limited (Energy Queensland) considers that the AEMC’s decision to utilise this term exclusively for ‘smart’ devices is likely to create confusion. We therefore suggest a term like ‘interactive distributed energy resource’ (iDER) be used to separate DER that have the ability to respond and interact with the network, from those that do not. Further, DER should not have to be co-located with customer load, as also suggested in the AEMC’s definition. This is because DER could also encompass grid scale energy storage located for network support purposes, which may also need to be considered in the operation of the network by any potential ‘Distribution System Operator’ (DSO). The AEMC’s proposed definition excludes passive systems, and thus the management and impacts of solar PV are excluded from the project’s scope. This is not consistent with the impacts of DER and will likely constrain the aim of the project and its capacity to manage the impact of DER on distribution networks. We note the AEMC’s comments that without smart control the mechanisms to manage solar PV differ to the mechanisms a DSO model would deliver. However, as Queensland has one of the highest penetration rates of solar PV in the world; the network constraints and impacts of such levels of exported energy would need to be considered and integrated into any system managing ‘iDERs’, as this two-way flow of energy will impact the manner in which the interactive energy resources need to respond. Further, levels of solar PV penetration would also need to be considered for planning purposes.

Project Scope	
Do stakeholders support this project scope?	The project scope tends to focus in part around the point that: "it is preferable to consider how our existing understanding of transmission network operation translates to distribution, and whether particular responses that maybe practical and appropriate at the transmission level can and should be applied at the distribution level". As the AEMC suggests, when examining whether transmission appropriate solutions are applicable to distribution networks, much care must be taken as low voltage networks are very different to transmission, and are difficult to control without some form of automation. From a technical standpoint, in addition to the dot points outlined by the AEMC in regards to the difference between transmission and distribution networks, other factors to consider include: • Data held in respect of distribution networks is typically not of the standard held in respect of transmission networks. This is particularly the case for deeper areas of the network, and given the relative size of such networks, the cost of improving access to data is currently prohibitive. • Transmission networks have complete remote monitoring and metering at each connection and asset point which, with the exception of Victoria, distribution networks do not have. While the outcomes of the Power of Choice review will eventually result in the power flow data becoming available at 30 minute intervals, this will not be for operational purposes (i.e. real-time and at smaller intervals) and will not include voltage, power factor etc. (which transmission network have and utilise) without additional cost to the DNSP to source from Metering Coordinators; if this data is in fact available. • Transmission networks have significantly more remote control, and are typically more meshed, which is important in the management of DER. • DNSPs generally do not have as sophisticated Distribution Management Systems

(DMS) as transmission network service providers (TNSPs), and thus lack the capability to remotely monitor and control their networks (both through automation and manually) from their control centres. Further, in some instances DNSPs still operate pin boards (etc.) which inhibits their ability to operate the network with DER.

- Distribution networks lack the same level of flexible reactive power support devices that transmission networks have (e.g. static var compensators (SVC)). This is generally on the basis that these technologies do not exist, are not mature in their application, or are not available at the required capacity.
- Distribution networks will have different stability impacts to transmission network. Specifically distribution networks will typically accommodate a very large number of DERs, resulting in increased power quality impacts (voltage fluctuations and harmonics) and islanding impacts.

Energy Queensland recommends the scope also consider the development and application of Australian Standards to DER. There appears little doubt that eventually DER will need to be managed to ensure it does not negatively impact distribution networks, and as such remote control capability of DER should be reflected in Standards. In this regard, it should be noted that research indicates that pricing signals alone are not sufficient to secure meaningful maintenance of loads.[1] Indeed, pricing signals alone can negatively impact the network, for example, when Electric Vehicles/batteries all begin charging when the price to recharge drops. Further, the customer must wish to participate. Currently customer participation in these types of programs is limited. With the complexities of customer side technology, customer move in/move out, rental properties (etc.) there is significant risk that customers will choose not to participate. As such, third-party control capabilities need to be added before reliable demand response of DER is achieved.[2]

[1] Faruqui & Sergici (2013). *International Evidence on Dynamic Pricing*, pg. 5 concluding statement to the first paragraph states: "The use of enabling technology appears to increase demand response to levels above pricing-only observations for a given price ratio."

[2] Ibid

	Further, specifically excluding the National Energy Customer Framework (NECF) from the project's scope may also hinder future market design. As noted, ultimately, trading or dynamic interaction on the distribution network will rely on the average customer participating, which can be significantly impacted by NECF rules and regulations; such as connection timeframes, standards, and rules governing customer contribution to the costs of connection.
Is there anything that has not been flagged for consideration that should be?	As discussed above, distribution systems are fundamentally different from transmission systems and as such a more granular level of issues must be considered. These include: • The level of technical and engineering capability and functionality such as protection, communication, control and operational capability that can be required for distribution customer connections is less than that which can be required in respect of transmission connections. These constraints can have impacts on uptake rates, response capabilities, localised climate impacts, etc. and should therefore be considered as part of any investigations. • The distribution network is also physically and electrically closer to customers, and thus there are considerations around physical and electrical safety that may need to be factored into any future operating models. • Energex and Ergon Energy have obligations under the *Queensland Electricity Act 1994* and *Queensland Electricity Regulation 2006*, with regards to the operation and management of their supply networks, such that in the absence of amendment to those instruments, any uncontrolled proliferation of DER will impact on their ability to meet these obligations. • DER within a distribution network has to be considered both individually and in aggregate within a localised area, specifically when there is a lack of diversity in customer fuel source (e.g. solar) or technology type (i.e. inverter-based). • Distribution Proponents are generally less familiar with the technical requirements associated with their connection than a transmission proponent, especially in the

	case of smaller proponents. As such the cost of expert technical support for distribution proponents can be prohibitive. Therefore, the level of 'plug-and-play' connection solutions is becoming more the norm and in order for this model to succeed, increasing automation will be important. However, DNSPs' participation in this market will necessitate significant investment, the cost of which is currently prohibitive. • Distribution proponents are more likely to be both a DER and a load customer, whereas transmission proponents are more likely to be a generator or a load. • Transmission systems gain a greater benefit from diversified loads, where-as distribution systems can be impacted more heavily by the lack of diversification. For example, sudden cloud cover in one specific spot can remove all the solar PV generation off a distribution network, resulting in a step change in network loading. **Tariff Reform** As noted by the AEMC, tariff reform and the capability to send signals to customers or their agents to utilise distribution networks in the most efficient manner, is crucial to the cost-effective integration of DER and should be an important element in the design of future market models. However, while tariff reform is fundamental to improving the utilisation of the assets, tariff reform by itself is not a solution. System security can require a dynamic, fast, and complex response which tariff signals are not of themselves, capable of providing.
Is there anything that should be excluded from the project scope?	No comment.

DNSP Market Role	
Are there any other elements of a DNSP's role or current responsibilities that should be considered?	DNSPs are naturally the energy provider of 'last resort', in that they have a fundamental regulatory obligation to ensure each customer connected to their supply networks has access to a secure, reliable and safe electricity supply. Without a significant change to this fundamental obligation, it is difficult to envisage how the DSO role could be undertaken by any other market participant, particularly given the operational decisions of the DSO will ultimately impact the ability of a DNSP to comply with its obligations in this regard. It is also important to note that the time lag for any signalling between a DSO and the DNSP means it would unlikely be technically feasible for anyone other than the DNSP to perform a DSO role. Energy Queensland also considers it will be difficult for a DNSP to monitor, predict performance and manage a large penetration of DERs, without some investment. This is because DNSP's do not have visibility and have not developed models of the low voltage network. Further, under the Regulatory Investment Test – Distribution, DNSPs are required to consider the benefits of options to all those who produce, transport and consume electricity. Such a requirement means DNSPs should inherently apply the National Electricity Objective in all business cases. No other market participant has such a regulatory requirement or natural position in the market as the energy provider of last resort, and as such we consider DNSPs are best placed to provide a platform to monitor and control distribution networks.
AEMO's Market Role	
Are there any aspects of the regulatory framework that are not set out in sections 2.3 or 2.4 but which should be considered	Under current market arrangements, the Australian Energy Market Operator (AEMO) generally only has regulatory and market oversight of generators >30 megawatts. While AEMO is beginning to consider DER in their forecasting and planning work, Energy

through this project**?**	Queensland notes that the primary focus for AEMO remains on the National Energy Market impact at a state level, and the cumulative view of DER at a transmission level. That is, AEMO's primary focus is not on the impact or specifics of an individual connection or the impact at, for instance, a locality or individual distribution customer level.
Summary	
Should the coordination of distribution systems with distributed energy resources be centralised under the direct control of one body? Or should it be devolved and performed in a tiered manner?	Energy Queensland considers it unlikely that one body could reasonably have direct control of distribution systems with DER in a centralised capacity. Specifically, each jurisdiction and DNSP has a range of differing rules, customer types, technologies, network configurations and network technologies. Further, energy usage will naturally occur in a tiered manner with consumption and generation on site being foremost, moving beyond that to local area and ultimately to inter-city consumption. As such, any requirement of a DSO function will evolve from a need for very localised to state wide management, over many years. While we consider, the DSO function could be performed within a single DSNP, or over a single state (where possible) it could not reasonably be performed at a national level due the complexity in differences between the states and the sheer volume of DER. Having a DSO function per state would provide the capability to compile the necessary data for provision to AEMO at a cumulative local level, as it requires. Protocols could be developed to ensure the DSOs function equally across the market. The market should be enabled to develop unencumbered and protocols should cover 'access rights' for application as a last resort to ensure the network is not compromised.
Assessment Framework	
Do stakeholders agree with the Commission's framework and these	DNSPs are generally responsible for ensuring acceptable voltage and power quality. However, the voltage at a site with DER may be impacted significantly by the operation of the DER itself. Further, if the DER is used for market purposes, its operation may cause

principles of good market design?	voltages to be outside of regulatory limits, resulting in rectification costs for the DNSP. Energy Queensland considers that in such cases the costs of maintaining acceptable voltage and power quality on the network should be shared by the participant who is receiving a market benefit from the DER. Otherwise, DNSPs will be required to fund stability measures offered by the manufacturers of DER to mitigate any issues. This would see the DER market profit from the supply of stability measures to manage the impacts it creates and would also result in a potential cross subsidy in the market.
Is there anything that the Commission has missed, or is unnecessary?	Please refer to our comments on specific issues raised in the Consultation.
Are there any other issues the Commission should have regard to in considering possible market design options?	Energy Queensland notes there are a number of mechanisms available to AEMO to support its obligations for power system security at the transmission level. These include AEMO's *Power System Security Guidelines* and its ability in Queensland, under section 115A of the *National Electricity Law,* to enter into load shedding arrangements with a Registered Participant, or for the Minister to determine these arrangements if an agreement between the parties cannot be met. We agree with the AEMC that, if such protection measures are required at the transmission level then similar measures may be required for distribution to manage the impacts of DER (in the long term), and provide measures of last resort to ensure system stability. Furthermore, Energy Queensland notes there may also be other market based responses and new business models which evolve. The development of complex pricing to customers could facilitate third party (retailer or aggregator) management of the price risk in the variable tariff (so that the customer still sees a flat rate), potentially in return for demand control at the customer's premise, thereby offering DER management opportunities.

Distributed Energy Resources: Technical Impacts	
Do stakeholders agree with the Commission's assessment of the technical impacts of distributed energy resources set out above in sections 4.1 to 4.8?	Energy Queensland notes this is a complex area, particularly as the technical considerations are not necessarily consistent across all DER types and sizes, nor are DNSPs' networks configured in a consistent manner. Furthermore, as DER technology evolves, new information on the technical impacts of this technology will become apparent. As most DNSPs do not currently have data and modelling facilities sufficient to capture and understand such evolving impacts, most often the impacts are not able to be accurately considered, particularly in respect of new connections. As such we suggest the following issues also be considered: • Short Circuit Ratios (particularly in generation connecting >1 Mega Volt Ampere) and associated system stability and protection requirements; • The current lack of electrical and connectivity data for low voltage modelling; • Limited control capability in Medium Voltage / Low Voltage (LV) networks; • Losses in efficiency due to dynamic load unbalances; • The need brought about by the impacts of DER to operate closer to design limits – which was not expected when existing plant was designed; • The largely radial nature of distribution networks, especially at LV; and • Difficulties in forecasting network flows and its impact on operational planning. Additionally, while a DER may be able to utilise excess capacity without any issues, it should be considered whether the connection of that DER will in fact reduce the power transfer capability (PTC) of the network (e.g. short circuit ratios). This is particularly important as such a reduction in PTC may necessitate a subsequent DER connection proponent being required to fund the cost of rectifying the PTC impact as part of its connection costs, resulting in an inequitable cost impact.

Distribution Market Model – Energy Queensland Limited Feedback

Assessment of Opportunities	
Do stakeholders agree with the Commission's preliminary assessment of these opportunities, and possible solutions to address the technical impacts of distributed energy resources?	Energy Queensland recommends the AEMC also consider the preliminary work by the Victorian Essential Services Commission; that is demonstrating the value of DER to distribution networks is generally very low and very location specific. If the DNSP is forced to procure all demand side participation (including hot water) under new rules, then system stability will become a complex economic issue with AEMO, the TNSP, DNSP and other third parties all involved. Further, the trade-offs between the immediate and long term benefits should be considered, in that what is generally better for the longer term, incurs higher costs in the immediate term (e.g. the high capital investment required initially to achieve a level of monitoring, control, modelling, analytics etc. for avoided traditional network augmentation investment or asset duplication over the long run). Additionally, the need for a DSO, while apparent, could still be mitigated via technology and DNSP operation of smart grids. The creation of another market operator would only increase costs to customers for a service that appears most appropriately the responsibility of DNSPs, with the necessary and appropriate protocols in place.
Do stakeholders have any initial views on who should be responsible for managing these opportunities, or implementing possible solutions to the technical impacts?	As discussed, DNSPs carry a large part of the responsibility for managing safety, reliability and stability of supply and act as the energy provider of last resort. The ability to participate in the operation of a platform for DER would enable DNSPs to appropriately manage the trade-off between network assets and platform models.